Evaluating the Energy and Economic Sector Impacts of Water Regulations on the Shale Gas Industry

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Introduction

Hydraulic Fracturing Background

Hydraulic fracturing has been a very high profile issue in the energy field for the last several years. This is likely a result of hydraulic fracturing's role in stimulating the shale gas energy boom and the fact that the process has ignited controversy across the nation due to its high water use and the potential for contamination.[1]

Hydraulic fracturing (often colloquially known as fracking) is an extractive process used in removing petroleum and natural gas from tight rock formations. This process is accomplished by injecting millions of gallons of water, proppants, and chemicals into a horizontally drilled well. The relative percentages of substances in the fracturing fluid mixture vary, but one might see a typical percentage breakdown as 90% water, 9.5% proppants and .5% chemicals.[2] This combination, generally known as frac-fluid, is injected at high pressures to break up the shale formation, at which point the proppants (generally sand, or some other similar silicate) prop open the fractures and allow the gas contained in the formation to flow back to the surface.[3] While the process isn't new (it was developed in the early 20th century), only recently have increased petroleum and natural gas prices, and advances in directional drilling and the fracturing process itself made the process economically viable.[4] Consequently, the amount of hydraulic fracturing taking place has increased substantially in the last several years. An industry-government study recently found that up to 80% of the wells drilled in the coming decade may be stimulated with hydraulic fracturing.[5]

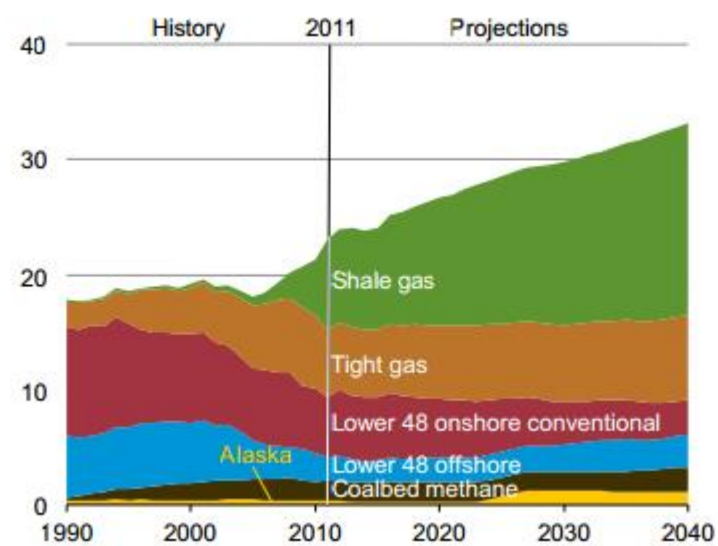

Figure 1: Natural gas production by source, 1990-2040 (Tcf). Source: EIA, 2013

The shale boom has vastly increased natural gas supplies leading to a drop in prices and an increase in the use of gas for electricity generation. Shale gas extraction has increased

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[1] Opposition to hydraulic fracturing has been fairly widespread, and most arguments against the process involve its potential for water supply contamination. This has been so much a part of contemporary culture that several mainstream movies have been made about fracking including the HBO movie Gasland which received an Academy Award nomination for best documentary.

[2] American Petroleum Institute, 2014, Hydraulic Fracturing: Unlocking America's Natural Gas Resources

[3] Cooley et al., 2012

[4] US Department of Energy, 2009

[5] American Petroleum Institute, 2014: Hydraulic Fracturing Q&A's

significantly in the last decade; in 2004 it accounted for 3.25% of domestic natural gas extraction, by 2013 this percentage had increased more than tenfold to 35.8% of total domestic gas production.[6] Figure 1 above shows historical and projected future shale gas production.

Energy generated by natural gas is less carbon intensive and generally regarded as cleaner than traditional coal generation.[7] As such gas from the shale boom has been heralded as a bridge fuel that will help the country transition away from coal based generation to a less carbon intensive energy mix.

A significant portion of the controversy surrounding this practice stems from water use. The following is a list of several roots of controversy, it is intended as a digest and is by no means complete.

First, the chemicals used in the process are often protected by trade secrets, meaning that there is little transparency in understanding exactly what chemicals are used in the process and how harmful they may be.

Second, more than half of fracking activity is done in areas that are under severe water stress. In many of these places water used in fracking is injected into saltwater disposal wells, thereby removing it from the hydrologic cycle, further exacerbating drought conditions.[8] Figure 2 (below) shows a map of water stress (as reported by US Drought monitor on January 7, 2014) overlain with the location of wells that have been hydraulically fractured between January 2011 and May 2013.

Third, the process has been tied to methane contamination of water sources near to hydraulically fractured wells.[9]

Fourth, the increased injection of produced water in injection wells for disposal has been shown to increase regional seismicity.[10]

Fifth, a percentage, usually between 10 and 30% (but sometimes as much as 80%), of the water used to perform the hydraulic fracturing returns to the surface as flowback and produced water. Flowback and produced water typically have high levels of salt and other contaminants.[11] Disposal of these products can be problematic, and spills have been known to happen as well.

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[6] EIA, 2013, Annual Energy Outlook 2013
[7] EPA, 2013, Clean Energy: Natural Gas
[8] Freyman, 2014
[9] Jackson et al., 2013
[10] Palmer, 2013; Smyth, 2012
[11] Cooley, 2012

Finally, due to its status as a petroleum extraction process, hydraulic fracturing has been exempt from regulation under the Safe Drinking Water Act since the passage of what has become known as the "Halliburton Loophole" in the federal Energy Policy Act of 2005.[12]

Due to its status as exempt from federal regulations, fracking is regulated primarily at the state level, leading to high variance in what regulations are in place from state to state. Some states have passed exceedingly stringent regulations, while others can be more laissez faire in what they allow.

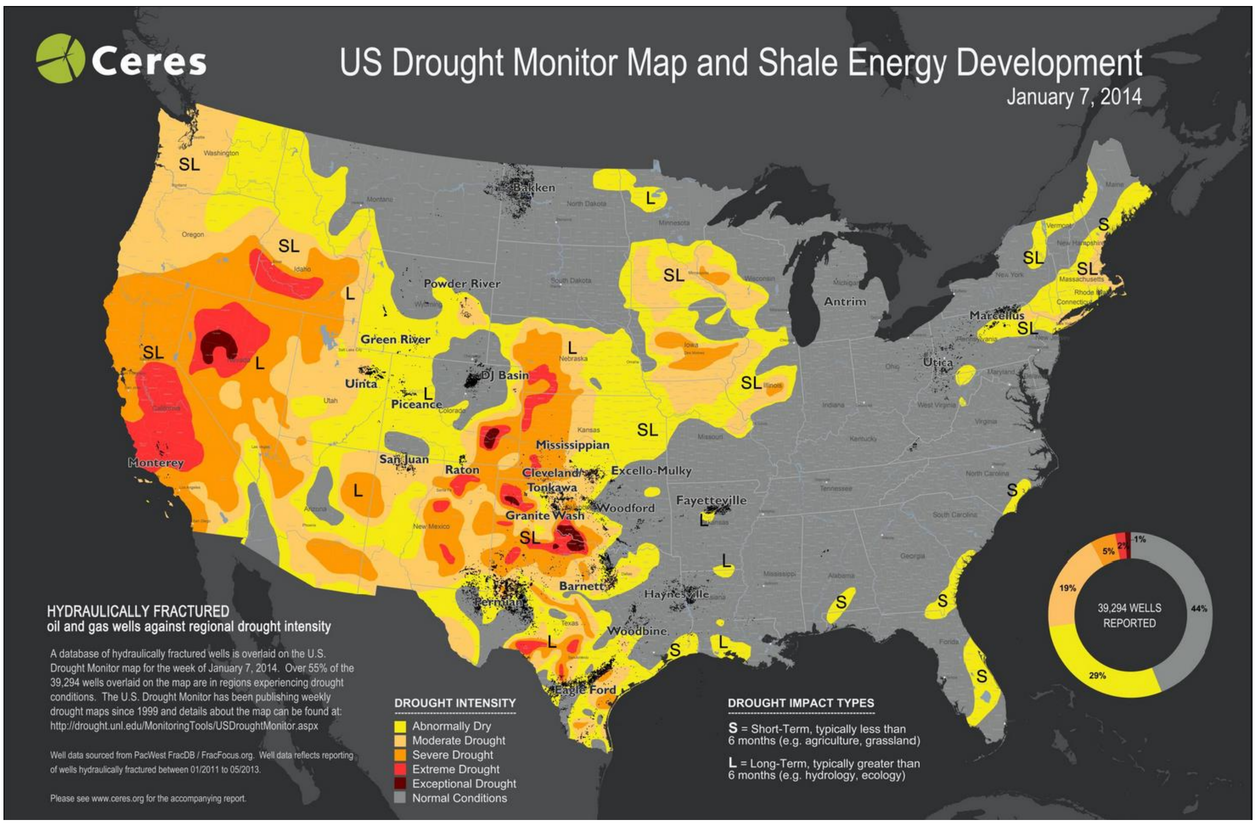

Figure 2: US drought monitor map & shale energy development.
Source: Freyman 2014

Water Stress and Hydraulic Fracturing

As seen in Figure 2, more than a quarter of fracking operations are occurring in areas with high levels of water stress, and more than half of all wells are in areas of some level of

[12] EPA, 2014, Regulation of Hydraulic Fracturing Under the Safe Drinking Water Act

water stress. Many of the places where fracturing is occurring rely on groundwater to meet water needs.[13]

Hydraulic fracturing occurring in areas with high water stress can lead to increased competition for groundwater resources. Additionally, high levels of fracking activity can deplete groundwater in already drought stricken regions. Nearly one in every three wells is located in an area with extreme water stress, which means that over 80% of available annual flows are already being consumed in these areas. Often this means that hydraulic fracturing activities are drawing on already taxed groundwater resources.[14]

Overuse of groundwater can lead to land subsidence and lower flow volume of surface streams. It is often the case that groundwater withdrawals are not as highly regulated as surface water supplies. Moreover, increased groundwater withdrawals may be unsustainable in the long run.[15]

Problem Statement

Due to the controversy surrounding hydraulic fracturing and its use of water resources, we proposed to address the following questions: first, which states have the strongest regulations, and what are the strongest regulations? Second, what would adoption of these policies mean for the industry as a whole? And third, if these policy changes did lead to dramatic effects in the shale gas industry, what would the effect be on the overall supply of natural gas, and what effects would that have on the US energy mix as a whole?

Our first step was to determine which states had the strongest policies, and what these strong policies were. Our second step therefore was to quantify additional costs that would result from adoption of these policies. Step three was to plug these costs into the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS), to see what the long term and short term effects of these policies would be.

Policy Background

Relevant Federal Regulations

Public and Indian Trust land are important areas for the fracking industry, accounting for about 13% of the United States natural gas production. Approximately 90% of these operations

[13] Freyman, 2013
[14] Freyman, 2013
[15] Freyman, 2013

are using hydraulic fracturing.[16] The Bureau of Land Management (BLM) within the Department of the Interior manages over 700 million acres of sub-surface mineral estate on these lands, and has recently issued their revised regulations regarding fracking. The previous regulations were more than 30 years old and no longer adequately served the modern techniques of hydraulic fracturing. Currently, the BLM is taking public comment on their proposed rules, and they will be finalized in the near future.[17]

There are a number of federal regulations, primarily under the jurisdiction of the U.S. Environmental Protection Agency, that relate to the water management of fracking. However, many of these regulations have loopholes that exempt the industry from following these rules. States may impose their own regulations that may close these loopholes, but are not required to do so. Described below are the most relevant federal policies relating to the water management of fracking.

The Clean Water Act is a comprehensive legislation that deals with discharges and pollutants entering U.S. waterways. This act prohibits the direct on-site discharge of wastewater from the oil and gas industry. This would require either the transportation of the water for further treatment, or an on-site recycling or treatment system. Since fracking requires a large amount of water, sources of water are normally located near the drill sites. The wastewater would have severe health and environmental effects if it entered a water body before being treated. Another section of the act, the National Pollution Discharge Elimination System (NPDES), regulates discharges from storm-water events. This could impact fracking, as water is many times stored in open pits near the well site; however the oil and gas industry is not required to obtain NPDES permits, unless a reported large event occurs.[18] Instead of being a proactive policy to prevent these spills, it becomes a reactive process.

The Safe Drinking Water Act (SDWA) regulates U.S drinking water quality, and would relate to fracking due to the underground injection of fluids. Groundwater is an important source of drinking water for many Americans, and injected contaminants could compromise the quality of the water. In 2005, however, the Energy Policy Act excluded fracking fluids and propping agents, unless diesel fuel was used, from the Underground Injection Control program. Fracking fluids may contain many harmful chemicals that could threaten drinking water supplies, but they are exempt from this act. The injection of produced and flowback water,

[16] BLM, 2013, Interior Releases Updated Draft Rule for Hydraulic Fracturing on Public and Indian Lands for Public Comment
[17] BLM, 2013, BLM Extends Public Comment Period on Proposed Hydraulic Fracturing Rule
[18] EPA, 2014, Natural Gas Extraction – Hydraulic Fracturing

which is a common method of disposal, is regulated under the SDWA. These are known as Class II wells, and the EPA has set requirements on where and how these wells can be utilized.[19]

The Resource Conservation and Recovery Act (RCRA) is the primary policy that governs hazardous and solid waste in the United States. Fluids that return from the well can contain many dangerous chemicals, dissolved solids, and radioactive materials.[20] Under RCRA wastes generated during the exploration, development, and production in the oil and gas industry are known as “special wastes” and are exempt from these federal hazardous waste regulations.[21]

The Emergency Planning and Community Right-to-Know Act (EPCRA) requires the reporting of the use of hazardous and toxic chemicals so that communities are aware and can be proactive in the planning of the accidental release of these chemicals. The Toxic Release Inventory section would require the public disclosure of these chemicals being used, and their potential impacts. While oil and gas companies are not specifically exempt, they are not listed as an industry that must report what they are using. There are thresholds of specific chemicals that would require notification if more than a certain amount is accidently released into the environment. This regulation could apply to fracking, depending on which chemicals are used in the company’s fluid.[22]

The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impacts and alternatives of certain projects, and in some cases an Environmental Impact Statement must be conducted. The Energy Policy Act of 2005 adds several categorical exclusions that relate to oil and gas development, which would exempt them from fulfilling a full NEPA analysis. This would help expedite the extraction of oil and gas.[23] While NEPA is very broad, the extraction, use, and discharge of water would all have to be examined during the environmental review of the process. If the process is fast tracked, it is possible that these concerns could be overlooked.

The Toxic Substances Control Act (TSCA) is another federal law that could potentially impact the disclosure of chemicals that are found in fracking fluid. TSCA grants the EPA authority to require reporting, record-keeping, testing requirements, and restrictions on different types of chemicals.[24] In the past, TSCA has not been used regarding fracking, but in 2011 Earthjustice filed a petition to the EPA for fracking to become regulated under the law.

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[19] EPA, 2014, Hydraulic Fracturing Under the Safe Drinking Water Act
[20] Hammer & Vanbriesen, 2012
[21] EPA, 2013, Crude Oil and Natural Gas Waste
[22] FracFocus, 2014, Chemicals & Public Disclosure
[23] Department of Interior, 2011
[24] EPA, 2013, Summary of the Toxic Substances Control Act

The EPA responded, and has begun the rulemaking process to at least partially regulate fracking chemicals under TSCA. The new rules are expected to be released in late 2014.[25] It is possible that after these new rules, not only would fracking chemicals need to be reported to the EPA, they may also have to be studied to see what their impacts are on the environment and public health.[26]

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) established the Superfund to help clean up hazardous waste sites. It allows the EPA to clean up these sites, and then designate responsible parties to be liable for the costs.[27] While the oil and gas industry did pay a tax to pay into the fund, it expired in 1985. The industry is also exempt from CERCLA's requirements, and liability would have to be proven in court.[28] If the harmful fluids did contaminate the area, it would take a significant amount of time before remediation could occur, as the liability could be held up through litigation.

While these are not the only federal regulations relating to water management and fracking, they are some of the more important ones. Many of them have exemptions for the oil and gas industry, so it has been left to the states to impose stricter regulations.

State Regulations

States with shale gas resources have developed their own policies on how to manage their water resources during hydraulic fracturing. States vary both on how stringent their policies are, and what different practices they regulate. As fracking has become a salient issue, new rules and regulations are continuing to be developed. This section aims at looking into different state policies that are crucial to water management during fracking.

While not directly related to water, it is important to note that several states have bans or moratoriums on fracking altogether. This is either because they oppose the practice, or that more research needs to be done. Vermont has banned fracking completely, while New York, North Carolina, Maryland, and New Jersey all have temporary bans while more research and regulations are being laid out. Colorado, Illinois, Michigan, New Mexico, Ohio, Pennsylvania, Texas, and West Virginia all have some local governments who have issued some sort of ban or moratorium as well. Some of these have been brought to court, with the rationale that only the states have the power to implement regulations, not the local government. A West Virginia

[25] EPA, 2014, Hydraulic Fracturing Chemicals; Chemical Information Reporting under TSCA section 8(a) and Health and Safety Data Reporting under TSCA section 8(d)
[26] Culleen & Sahay, 2012
[27] EPA, 2013, Superfund: Basic Information
[28] Earthworks, n.d.

court ruled against a local moratorium, and allowed for drilling to continue. The uncertain impact on both surface water and groundwater are surely part of the reasons that these bans and moratoriums are taking place.[29]

One of the most controversial aspects of fracking is the disclosure of what chemicals and substances that are being used in fracking fluids. Since these fluids are being stored on site, and then pumped into the ground, there is a grave concern that there is a threat to public health and the environment. As previously mentioned, some of these chemicals can be dangerous and harmful. The federal SDWA, and EPCRA would both help regulate this issue, but fracking is exempt from them. As a result, about half the states with fracking are requiring some sort of disclosure.[30]

Fracking companies have been reluctant to publish this information because they say that their chemicals and mixtures should be proprietary information, and be considered "trade secrets." They claim that their fluids give them a competitive advantage, and by giving out the compositions, other companies can use them and be more productive. As a result, states have developed provisions to allow for "trade secrets" to be exempt from disclosure, with varying severity. Pennsylvania and Arkansas are examples of states that require the disclosure and the concentration of the additives. Some states such as Texas, Alabama, and North Dakota have regulations that allow companies to claim "trade secrets" with very little, if any, justification. On the other hand, Wyoming and Illinois have stricter regulations.[31] Illinois requires the disclosure of chemicals both before and after fracking occurs, and to get a "trade secret" provision it must be approved by the state agencies strict review that their composition is unique, and has competitive value.[32]

When these chemicals are disclosed they are normally released to the corresponding state agencies, or FracFocus, which is a national hydraulic fracturing chemical registry. On this site you can look up individual wells and see what additives are being used.[33] "Trade Secret" information can be held privately in state agencies, and in some states, medical professionals have access to it.[34]

California's recent regulations mandate that trade secrets and the concentration of the chemicals that are being used be disclosed to the state agency after injection, and it would be

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[29] Keep Tap Water Safe, 2014
[30] Richardson, et al., 2013
[31] Mall, 2012
[32] State of Illinois General Assembly, 2013
[33] FracFocus, 2014, About Us
[34] Gruver, 2013

considered a crime if a person in the agency disclosed the trade secrets to the public. Like Illinois, California has a strict test for operators to prove that the trade secret is indeed unique. They are also allowed to randomly inspect on site what chemicals are being used to ensure they are being accurately reported.[35]

In 2013, a group of environmentalists in Wyoming took the state to court to obtain these trade secrets, arguing that the public has the right to know what is being pumped underground. The court sided with the state, allowing for "trade secrets" to remain out of reach for the public.[36] For complete information on chemicals to be disclosed, the state would have to require the disclosure of all chemicals, and not allow trade secrets. If a state required full chemical disclosure, litigation would almost certainly occur.

Since hydraulic fracturing requires a large amount of water, it would be advantageous for companies to locate drilling sites next to water sources. This poses a tremendous risk to these sources, as a variety of contaminants could unintentionally be released. To reduce this risk, some state require the drill sites to be located certain distances from these water sources. Depending on what the source of water is, there may be stricter regulations on it. Sources of public drinking water supply seem to have the furthest setback, such as 1,500 feet in Illinois[37] and 2,000 feet from certain public water supplies in Michigan.[38] These are some of the furthest distances, as the average distance from public drinking water is 334 feet.[39] Private drinking wells also have a further setback than other bodies of water, such as 500 feet in Illinois[40] and 300 feet in Ohio.[41] Other water sources, such as lakes, trout streams, and ponds have certain setbacks depending on the state. North Dakota uses a discretionary approach, and restricts well sites from being "hazardously near" bodies of water. [42] For all states, these setbacks normally occur from the well sites, but New Mexico and Arkansas measure from the location of the pits and tanks. Not all states have setback requirements, as Texas, Louisiana, South Dakota, and several others have no evidence of regulations.[43] If a significant risk was posed, these states without setback regulations could always deny access to drilling through the permitting process. There are just less precautionary measures to minimize the threat of negative impacts to these water sources.

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[35] California State Senate, 2013
[36] Michigan Department of Environmental Quality, 1994
[37] State of Illinois General Assembly, 2013
[38] Michigan Department of Environmental Quality, 1994
[39] Richardson et al., 2013
[40] State of Illinois General Assembly, 2013
[41] STRONGER, 2011
[42] North Dakota DMR, 2010
[43] Richardson et al., 2013

Due to the large concern for the potential contamination of nearby water sources, some states are requiring pre-drilling water testing to establish a baseline water quality. With a baseline established, future water testing can be compared to see if any impacts have occurred due to drilling. While the majority of the states do not require this, those who do normally require at least two water wells samples within a given area. The average radius is .44 miles, but range from .09 miles in Virginia to 1 mile in Oklahoma.[44] These tests generally come from existing water wells, but some states may require testing from other sources of water. Illinois requires the testing of all sources of water within 1500 feet of the well site. They also require the periodic testing of these sources of water after fracking occurs.[45] Colorado and Wyoming also require testing of water sources both before and after drilling. While there are no pre-drilling testing requirements in Pennsylvania, any company that does not do pre-drilling testing is barred from claiming that the water contamination was preexisting. As a result, most companies actually do pre-drilling water testing.

Fracking can require millions of gallons of water for each well, so some states are creating regulations to oversee the quantity and location of the water that is used. Almost all of the states require a permit for withdrawing ground or surface water, but for some of these states a permit is only needed if a certain threshold is met. For example, anyone who withdraws more than 35 gallons per minute of water must get a permit in Montana.[46] In Texas, you only need a permit for withdrawing surface water.[47] In a few states, you do not need to get a permit, but if you do withdraw a certain amount you need to register and report the quantity, such as over 10,000 gallons of water a day in Tennessee.[48] Kentucky seems to be the only state to have no regulations on water withdrawals for fracking, as the oil and gas industry is exempt from their regulations. Pennsylvania, West Virginia, and Illinois all have comprehensive water withdrawal plans for the full life cycle of the water, which includes where the water came from, how much is taken, and what impacts may occur.[49]

During the whole process of hydraulic fracturing large quantities of fluids may be stored at the drill site. They could be fracking fluids, withdrawn water, flowback, produced water, or other liquids. In order to minimize environmental impacts from events such as heavy rain, or infiltrating the ground, states have developed a variety of different policies. These fluids are stored either in open pits, or sealed tanks. One of the issues with open pits is the possibility for

[44] Richardson et al., 2013
[45] State of Illinois General Assembly, 2013
[46] Montana DNRC, n.d.
[47] Richardson et al., 2013
[48] Tennessee DEC, n.d.
[49] Richardson et al., 2013

rain water to overflow them, and the fluids could be released into the surrounding environment.

To reduce this problem, over half of the states have developed freeboard requirements, which set a minimum distance between the highest level of fluid and the top of the pit. This number varies from 1-3 feet, where Oklahoma and Montana are the strictest. Most states also have standards for their pit liners, including thickness, material, permeability and other characteristics. The restrictions on freeboard and liner vary depending on what fluid is being stored in the pits. While 16 states have no restrictions on what the fluids can be stored in, some states have required sealed tanks for certain fluids.[50] In Michigan, pits may be used for drilling fluids and muds, but tanks must be used for wastes after fracking occurs.[51] Illinois requires that all fluids being stored on site must be stored in sealed tanks at all times, and that they are removed within 60 days. They do allow a reserve open pit to be used if only if there is a lack of capacity due to more produced water coming back up. This fluid must be moved from the pit within 7 days.[52]

Since the underground injection of the wastewater from fracking is a common practice for companies, almost all of the states have created a regulatory program. The injection wells are still regulated by the EPA, but states can add other specifications. These might include what type of fluids can be injected, or site specifications for the well. For example, Montana requires the underground injection of all fluids that contain more than 15,000 ppm of Total Dissolved Solids. While Pennsylvania allows for the underground injection, due to its geology and other factors, injection in Pennsylvania is largely impossible. Most of the injections from the wastewater in Pennsylvania is shipped and injected in Ohio.[53] The only state to outright ban the underground injection of fluids is North Carolina.[54] There has been a concern that additional seismicity could result from these underground injections. While the regulatory programs try and minimize the risk of these seismic events, in several instances earthquakes have been attributed to these disposal wells.[55] As a result, several states have bans or moratoria on the injection of fluids. Arkansas and Ohio have moratoria against injecting near areas with seismic activity, and Fort Worth, Texas has a ban on deep injection wells.[56]

[50] Richardson et al., 2013
[51] Michigan Department of Environmental Quality, 1994
[52] State of Illinois General Assembly, 2013
[53] Abdalla, Blun, & Edson, 2011
[54] Richardson et al., 2013
[55] Everley, 2013
[56] Richardson et al., 2013

Apart from the underground injection of wastewater, states have also developed policies regarding other types of disposal. In 11 states, certain wastewater is allowed to be used for land treatments, such as ice and dust control. Many states also allow for pit disposal of wastewater, such as New Mexico, Kentucky, and South Dakota. Depending on the state, they may allow for evaporation pits, impoundments, pit closures, and other practices. In 13 states, water can be shipped to treatment facilities, but may be limited to certain types of fluids. Under certain conditions, 9 states allow for wastewater to be discharged to surface waters. They must be treated and meet specific criteria before this can occur. If the wastewater is being shipped for further treatment, or recycling, a permit or record keeping may also be required. While recycling is not mentioned in every states regulations, it is assumed to be allowed and has been growing in popularity, especially in Pennsylvania.[57]

Once a well has been drilled, cement casing is put in to support the well, and to make sure that no substance leaks out or into the well. This is done by first drilling the hole, and then filling the area between the earth and the well with cement. The types of casings are categorized into three segments, the surface, intermediate, and production casing. As the name implies, the surface casing is the first casing created, which accounts for the top portion of the well. It normally extends to just below the water table to ensure that it is protected. Then the intermediate casing is put into place, and lastly the production casing, which is near the hydrocarbon zone. The amount of casing required varies by state, but almost every state requires a full surface casing that goes all the way up to the ground level. Indiana, Pennsylvania, and Kentucky require that the entire intermediate casing is completed to the surface, while Arkansas requires the production casing completed to the surface.

Most states require a certain distance from either water sources or hydrocarbon zones to be cased. For example, in Texas, all casings must occur 600 feet above hydrocarbon zones, and in Wyoming, casings must occur within 120 feet of fresh water zones. Some states such as West Virginia and Michigan address the intermediate and production casing lengths in their permits.[58] To test the integrity of these casings, there are a variety of tests that can be performed. One type is log tests, which measure the loss of acoustic energy as it is emitted through the well. Another is pressure tests, which identify weak areas after a certain amount of pressure is applied to the wells. Every state requires some sort of test to be performed to ensure that the well has been done properly.[59] These casing provide essential protection for ground water, as they prevent substances from leaving the well.

[57] Richardson et al., 2013
[58] Richardson et al., 2013
[59] Syed, 2011

As hydraulic fracturing continues to evolve and more is learned about the practice, it is likely that states will continue to adopt new policies. Depending on the state, some have stricter regulations than others. This is due to geologic features, pro-industry government leaders, as well as other factors.

Industry Standards

The American Petroleum Institute (API) is a national trade organization that represents the interests of the oil and gas industry. With over 500 corporate members, they research, educate, analyze and lobby for their constituents. One of the important things that they do is create industry standards and recommended practices for almost all aspects of the industry. Many companies use these as guidance documents during their operations. While there are many of these relating to fracking, the most important one regarding water use is known as API Guidance Document HF2 “Water Management Associated with Hydraulic Fracturing.” There are other documents that have sections on water, but this is the one document dedicated solely to water management. The document was created to describe the industry best practices to “minimize environmental impacts associated with the acquisition, use, management, treatment, and disposal of water and other fluids associated with the process of hydraulic fracturing.” The first edition of this document came out in 2010, and it is also the most recent one. API is currently working on an updated version. There are several recommendations regarding the initial use of water that can be found in the HF2. [60]

First, operators should “engage in proactive communication with local water planning agencies” to ensure regulatory compliance and that local water supplies have not been compromised. Second, API believes that it would be beneficial to develop a basin-wide hydraulic fracturing plan that may include potential water sources (with a priority to wastewater or non-potable water, if feasible), volume of water, transport, and treatment or disposal options. The potential impacts from these sources should also be considered, such as the impacts to fish and wildlife, drinking water supply, timing of withdrawals, and other environmental impacts. Wells should be drilled an “appropriate distance” from various water supplies. Third, operators should study the water quality characteristics of the area, and if necessary work with regulators to assess the baseline characteristics of the water. On certain sites, pre-drilling sampling should be considered. Additives to the water should be minimized, and alternatives that are more environmentally friendly should be assessed and used if feasible.[61]

[60] American Petroleum Institute, 2013
[61] American Petroleum Institute, 2010

Once the water has been used, API recommends that operators should examine which waste management and disposal practices would work best for their wastewater based on the characterization and disposition of the water. The planning should consider unexpected delays so that they can be properly managed. Also, operators should be familiar with what permits may be required for their treatment facilities or disposal wells. Reusing or recycling flowback and produced water should be the first method that they evaluate. If the wastewater is going to be transported to other locations, alternative strategies should be considered, as this can be very costly. Operators should take measures to reduce or mitigate the transportation impacts to the local areas to reduce traffic volume, noise and other negative impacts relating to high volumes of trucks. [62]

In general, the API recommendations are to consult with local, state, and federal government officials to make sure that they are complying with all laws and regulations. While the HF2 does give a lot of information about being proactive and minimizing the environmental impacts during operations, such as doing continuously monitoring water or using safer and fewer chemicals, it throws in ambiguous language such as “if necessary,” that might make an operator ignore the recommendation. There are good things in this document; however, they make everything that isn't already regulated seem optional. This was expected, as the document was created within the industry.

State by State Comparison

Since hydraulic fracturing for shale gas is almost entirely regulated by the state that it is occurring in, it is important to look at each state as a whole to determine the strength of water regulations. We have created a map that breaks each state we looked at into strong, intermediate, and weak, based on the regulations identified above. States with no shale formations, or those who are currently in the policy-making process were not included. To do this, each type of regulation had criteria to place them into each category. Then, an aggregate score was calculated based on all of their regulations. For each regulation, the criteria were based on the characteristics shown in figure 3 below:

[62] American Petroleum Institute, 2010

Regulation	Weak	Intermediate	Strong
Chemical disclosure	No Disclosure	Partial Disclosure	Full Disclosure
Water Setback	None	Less than 500 feet	Greater than 500 feet
Water withdrawal/management plans	None	Permit of Registration Required	Complete management plans required
Water Testing	None	N/A	Required
On-site Storage	Any storage allowed	Certain restrictions on what fluids can be stored in	Sealed tanks are required for all fluids
Underground Injection	Allowed	Local bans or moratoriums	Banned
Casing Requirements	Only surface casing required to top	Intermediate or production casing required to top of well	All casings required to top of well
Pressure and Log Tests	None	N/a	Required

Figure 3: hydraulic fracturing regulations and their relative strength

To determine which states fell into each category, we applied a scoring method to each regulation. Weak regulations were scored 0, intermediate regulations were scored 5, and strong regulations were scored 10. Each states score was determined by summing all of these numbers and breaking the states into three categories. The results can be seen in figure 4 below.

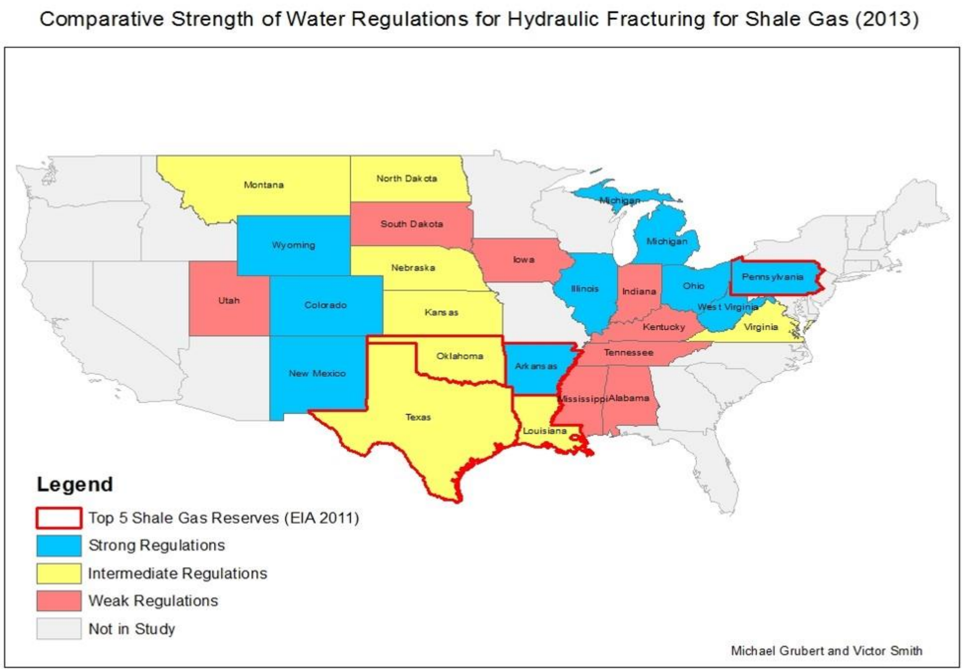

Figure 4: Comparative Strength of Water Regulations by State

Cost for all states to implement strong regulations

Strict regulations may be necessary in order to best protect our valuable water supplies. Since not all states have these regulations, we wanted to calculate the additional cost incurred to each state if they implemented these strong regulations. This, however, is not easy to quantify, as each state has unique characteristics, such as shale formation depth and supply of water. By identifying the current conditions of each state, we can determine an estimated cost for each regulation. In this scenario analysis, we looked into the cost of fully casing a well, storing all fluids in sealed metal tanks, performing baseline testing, and recycling the wastewater. The other regulations that were analyzed would be almost impossible to quantify, so they have been excluded. The method for determining these costs are outlined below.

Well casings

The first step to determine the addition cost of fully casing the surface, intermediate, and production casing was to determine the average depth that a well is drilled in each state. Each state has a number of different shale formations within them, and can vary from 1,000-15,000 feet deep. After locating each shale formation that contains gas in a particular state, the average depth of all these shale's was calculated. In hydraulic fracturing though, the vertical depth is only one part of the equation. To account for the horizontal part of the well, we assumed a uniform number of 4,000 feet for the lateral based on data from Halliburton, which is a leader in the field.[63]

The next step was to determine what the average length of each casing would be based on the determined depth and horizontal lateral of the well. We assumed that 1/3 of the vertical depth would be categorized as surface casing, 2/3 of the vertical depth to be the intermediate casing, and the full length of the vertical and horizontal lateral to be considered the production casing.

With these casing lengths, we now can compare them to what the state casing regulations are. Then depending on how much casing is required, we can find an additional amount of each casing that would be needed if strong regulations were put into place. Since almost every state requires the full surface casing to be cased to the surface, there was no additional casing required. The intermediate and production castings have much more heterogeneous regulations. For states that use permits to determine the casing length, we assumed no regulation, as there is no specific amount identified. Some states require a certain distance from water sources or from hydrocarbon zones. To calculate the casing required near water, we found an average depth of ground water in the United States to be 70 feet below the surface, using USGS data.[64] We also assumed that the only hydrocarbon areas were in the horizontal lateral section of the well. By subtracting the intermediate and production casing required by regulations in each state, from the amount required for full casings, we then determined the addition casing that would be required.

The main cost for these additional casings is going to be the cost of the cement, which is sold at a price per volume. To be able to quantify this, we needed to convert the additional casing lengths to a volumetric measure. Each type of casing is a certain size, so the volume will vary per foot in each casing. Using average thickness from Marcellus Shale wells, we determined the radius of surface casings to be 11.2 inches, 9.62 inches for intermediate casings, and 5.5 inches for production casing.[65] Using the area of a cylinder formula, and assuming that half the volume is for the well hole, we can calculate the total amount of additional cement needed. Finally, by multiplying the total volume of cement by the price of cement ($100/cubic yard), we can calculate the additional cost per well in each state if they implemented strong policies.[66] Costs are shown below in figure 5. Due to the wide variance in ranges found for all states, the casing costs are displayed in a range.

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[63] Halliburton, 2008
[64] USGS, 2014
[65] Marcellus Shale Coalition, 2014
[66] Buzzle, 2013

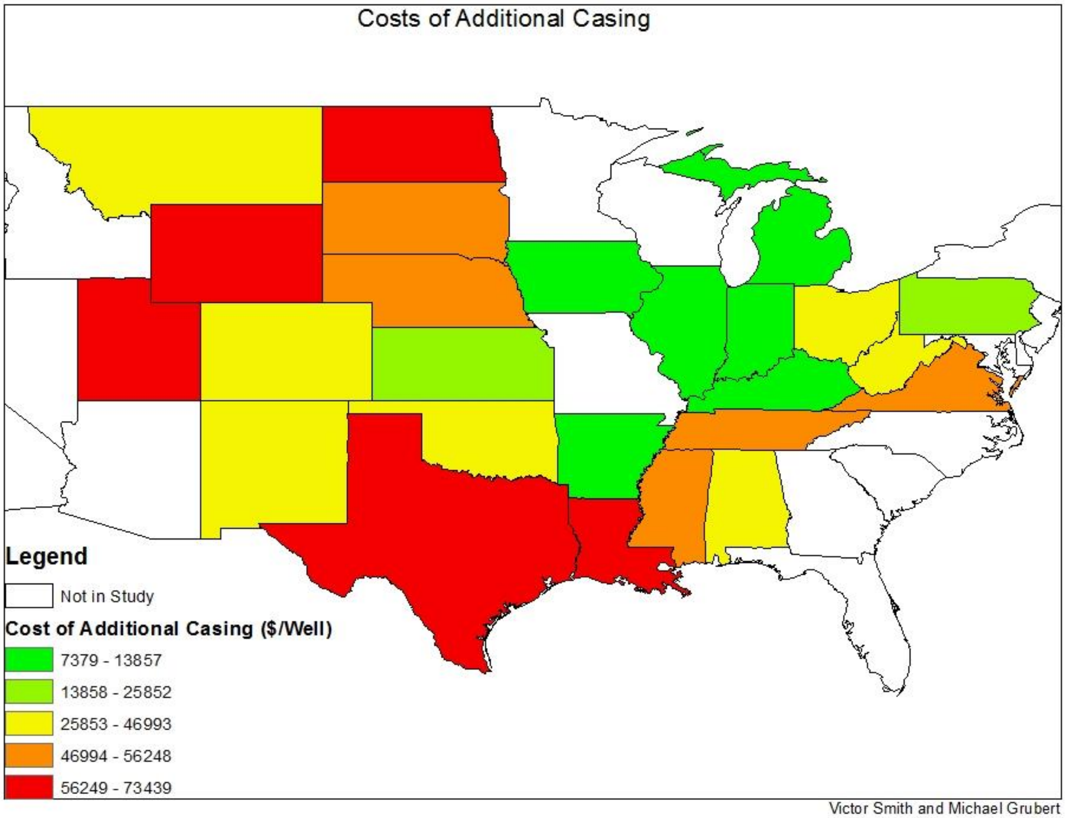

Figure 5: Cost of additional casing by state

Baseline Testing

While in an ideal policy, all water sources within a certain distance would be tested, however, this is impossible to quantify due to site specific conditions. As a result, we assumed a strong policy of requiring the testing of 4 water sources, before drilling occurs, and then 6, 18, and 30 months after drilling has occurred. These dates were based off of Illinois's baseline testing requirements, which are the strongest.[67] In total, 4 sites would be tested 4 times, for a total of 16 tests. The cost per test was determined to be approximately $500, based on several different price quotes for fracking water quality tests.[68] We then compared this strong regulation to each state's current policy to determine a cost. Most states do not require baseline testing and have an additional $8,000 cost for all of these tests. Others have a variety

[67] State of Illinois General Assembly, 2013

[68] Community Science Institute, n.d.; Water Test Wholesale, n.d.; Phillips, 2011; Don't Fracture Illinois, 2013

of different regulations, and depending on how many tests were required, a state will have a different price. The distance from well site where these water tests were required was not factored into our calculations, as that cannot be quantified. Baseline well testing costs are shown below in figure 6.

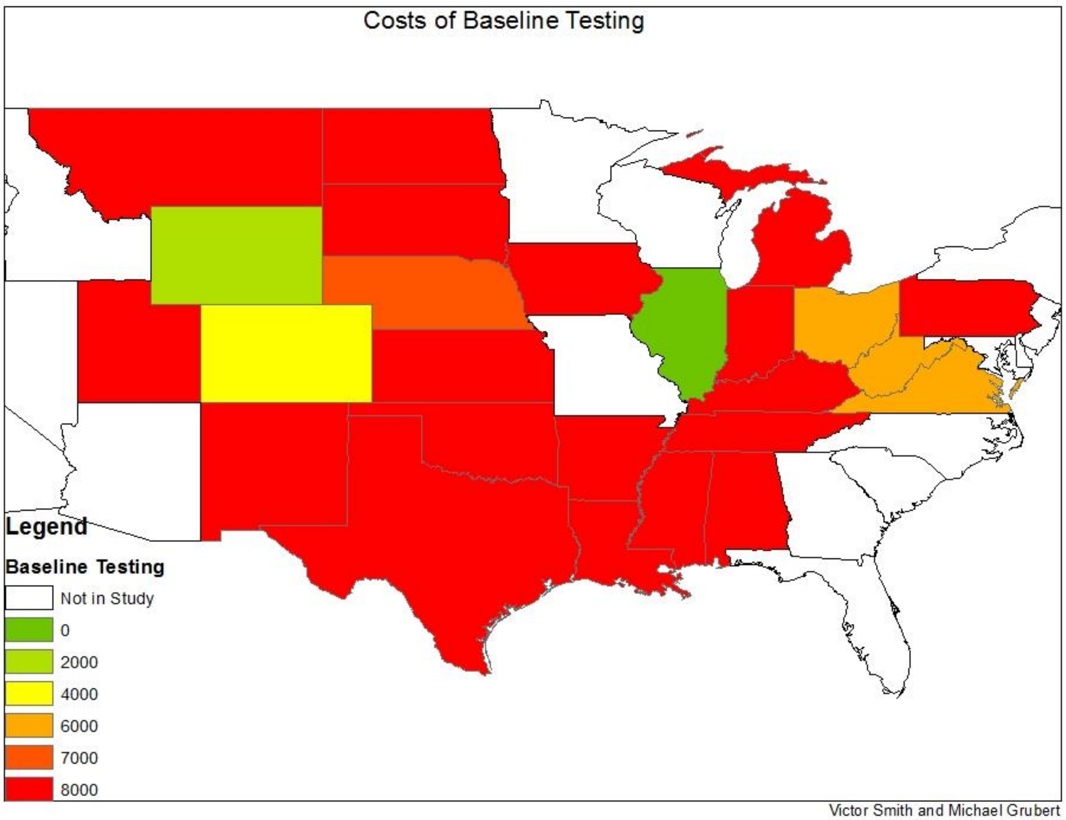

Figure 6: costs for additional baseline testing by state

Determining Cost of Recycling Flowback Water

Finding the cost of recycling flowback water was a multi-step process, primarily because it involved finding the cost above the status quo. Data on current disposal paradigms are generally hard to find. However, sources tend to agree that the prevailing and preferred method for flowback disposal is transport to an offsite class 2 salt water disposal well (SWDW) for underground injection. The American Petroleum Industry's document on water management best practices associated with hydraulic fracturing (HF2) lists underground injection as the first option for waste water disposal.[69]

Costs associated with disposal are not simple to model for a variety of reasons. Primarily, hydraulic fracturing wells and SWDWs are often not geographically proximate. Costs associated with transport to disposal tend to be the largest and most variable of the costs associated with the entire process and can represent up to 84% of the total cost of disposal, according to one report.[70]

Second, the amount of water used for each fracturing job is variable, some areas report as little as half a million gallons of water per fracture, while the EPA estimates that the typical horizontally drilled well requires two to four million gallons of water.[71]

Third, injection costs themselves are variable and have tremendously variability even within states. For example, the cost of injection of an individual barrel of flowback in Louisiana varied from between $0.50 to $7.[72]

Fourth, flowback returns themselves are variable. The amount of water that returns after injection can vary from as little as 10% to as high as 75%.[73]

Fifth, the costs of recycling are variable as well. Prices for recycling were generally quoted by the barrel and ranged between $2 per barrel and $7.50 per barrel.[74]

Therefore in order to model the costs associated with flowback recycling by state it was deemed appropriate to make several simplifying assumptions regarding the average well.

First it was assumed that the average well required 3 million gallons of water. While it is the case that different shale formations have different water requirements[75] some states have multiple shale formations, each with different water requirements. Data on water use for each well is available for select states via fracfocus.org but the data is not usefully aggregated. Moreover, disclosures on FracFocus are self-reported, and occasionally underreported or omitted. For example, last year Colorado issued several fines for late reports to FracFocus. In Pennsylvania and Colorado in 2012 more than 20% of reports were late.[76] Moreover several

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[69] Cooley, 2012, 23; API, 2010, 20-21
[70] Stepan, et al., 2010, 17
[71] Stepan, et al., 2010; 1, EPA, 2011, 22
[72] Puder & Veil, 2006, 40-43
[73] EPA 2011, 42
[74] Acharya et al., 2011, 71; Rassenfoss, 2011, 50; Puder & Veil, 2006, 47
[75] EPA, 2011, Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, 22
[76] Soraghan, 2013

states do not require that companies report water volumes to FracFocus.[77] Three million gallons was used as a standard figure in order to circumvent differing reporting requirements and uncertainty regarding divergent water requirements for shale. The three million gallon figure is the middle of the EPA's estimate of water required for horizontal wells.

The second assumption made was that the average well would return 30% of the water injected into it. This number lies relatively centrally in the estimates provided by the EPA and is the mean number in the flow rates reported by RFF.[78]

The third assumption made was that the cost of treatment for recycling would be $5 per barrel, which is the cost per barrel quoted in Puder & Veil and within the range quoted by Rassenfoss in the Journal of Petroleum Technology. It was further assumed that recycling costs were equal across all states.

The fourth assumption made was that transport costs accounted for 70% of the costs associated with injection. 70% is the center of the range reported by Stepan et al.[79]

Fifth, it was taken into account that Pennsylvania already recycles or reuses nearly 90% of its flowback.[80] The cost to Pennsylvania for recycling was correspondingly decreased by 89.8%.

Taking all these assumptions into account it was possible to model the differences between injection and recycling costs for each NEMS region.

The first step was finding the cost of injection in each state. Puder & Veil conducted a survey of SWDW operators in 2006 to find the cost of injection. Not all states had respondents and as stated earlier some states had a wide range of reported costs. Therefore the average of the reported costs was selected as the cost used for each state. Injection costs for Pennsylvania and Ohio, not included in Puder & Veil, were taken from Rassenfoss.[81] Injection cost for each well was found by multiplying average cost by average flowback return.

Since the assumption was made that transport represented 70% of the cost associated with disposal was transport, the corresponding assumption was made that injection represented the other 30% of the cost. Correspondingly, the cost of transport was determined by multiplying injection costs by seven thirds (7/3). The sum of these two numbers was then

[77] Vinson & Elkins, 2013
[78] EPA, 2011, Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, 42; Richardson et al., 2013, 46
[79] Stepan et al., 2010, 17
[80] Maloney & Yoxtheimer, 2012, 278
[81] Puder & Veil, 2006; Rassenfoss, 2011, 50

subtracted from the cost of recycling flowback (which was a constant[82] for all states, except Pennsylvania, which was 10.2% of the total of other states).

Each NEMS region had at least one value for recycling after this process. For those NEMS regions with more than one value, a weighted average was taken. The factor used in weighting was natural gas wells operating by state in that year. For example, for NEMS region 7, which consists of Arkansas, Louisiana, Texas and Oklahoma, the formula for obtaining the weighted average was the sum of each state's determined cost of recycling above injection, multiplied by the number of natural gas wells in that state and divided by the total number of natural gas wells in the region. Figure 7 shows the cost of recycling in each state.

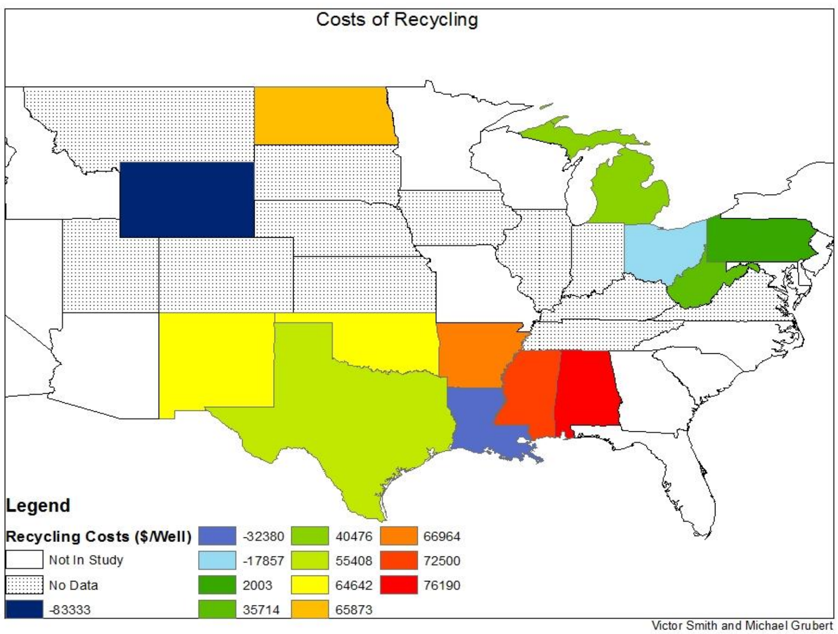


Figure 7: costs of recycling flowback by state

Determining Cost of Storage Tanks

Determining the cost of storage tanks also involved several stages of modeling. For consistency, several of the assumptions made in the previous model were carried over to this model. Specifically, the assumption that each well requires three million gallons of water and

[82] The actual dollar number was $107,142.86, which is equal to 3,000,000 (number of gallons) *.3 (flowback rate) / 42 (number of gallons per barrel)* 5 (dollar cost per barrel).

returns 30% of that amount as flowback was continued. In addition to these assumptions it was necessary to estimate a typical flowback schedule (i.e. the rate at which wastewater returns from the formation). Typically flowback rates are much higher immediately following the fracture and decrease as time increases. Acharya (2011) provides ranges of rates of flowback after the date of fracture. The rates shown below in figure 8 show the modeled flowback rates.[83]

Flowback Schedule				
	Bbls/Day	Percent of frac fluid	Total bbls per bloc	Aggregate
Days 1-5	2142.857143	15%	10714.28571	10714.29
Days 6-15	571.4285714	8%	5714.285714	16428.57
Days 16-30	238.0952381	3%	3571.428571	20000
Days 31 to 90	23.80952381	2%	1428.571429	21428.57

Figure 8: schedule of flowback returns

The next assumption made was that a recycling process would be capable of recycling roughly fifty gallons per minute. This number was taken from the Acharya (2011) study which showed the feasibility of treating water at 50 gallons per minute. Given this rate of treatment and the above flowback schedule, and assuming that recycling begins the day after flowback begins, figure 9 at the right shows the amount of untreated flowback remaining. The amount of wastewater peaks at 3,857.14 barrels on day 5. After that point, the treatment system is able to treat the effluent faster than it emerges from the well.

Day	Flowback Remaining (barrels)
1	2142.857143
2	2571.428571
3	3000
4	3428.571429
5	3857.142857
6	2714.285714
7	1571.428571
8	428.5714286
9	0
10	0

Figure 9: amount of untreated flowback on site.

In order to quantify costs associated with storage, it was necessary to find out what it would cost to store 3,857 barrels of untreated water in steel tanks. Costs of steel tanks were found by calling several tank companies and asking for quotes for flowback storage tanks.[84] After receiving quotes for several tanks, it was determined that the 12,000 gallon tank had the lowest cost per barrel of storage (each tank cost $12,000, so the cost per barrel of storage was

[83] Acharya, 2011, 30
[84] Only one responded. Granite Environmental (2014).

$42). In order to store the peak amount of flowback modeled, one would need fourteen of these tanks. The cost of fourteen of these tanks would amount to $168,000.

In order to determine how much of an increase over the current cost of doing business this $168,000 represented it was necessary to first determine what original costs were. It was assumed that operating companies would pursue the least cost option. The cost of constructing a lined impoundment pond to contain flowback was found to be between $60,000 and $80,000 in the Marcellus.[85] The middle value of this range, $70,000, was selected as the cost to represent lined pit construction. This cost was assumed to be constant across all regions.

The final estimated cost of storage using only steel storage tanks therefore represents the cost of acquiring tanks less the cost of a storage pond. How much of an increase this represents depends on the current policies in place in each state. For example, Illinois requires that all flowback be stored in steel tanks, so the total increase is $0. Some states require either pits or tanks, and some require tanks for specific fluids. Those with the most lax requirements

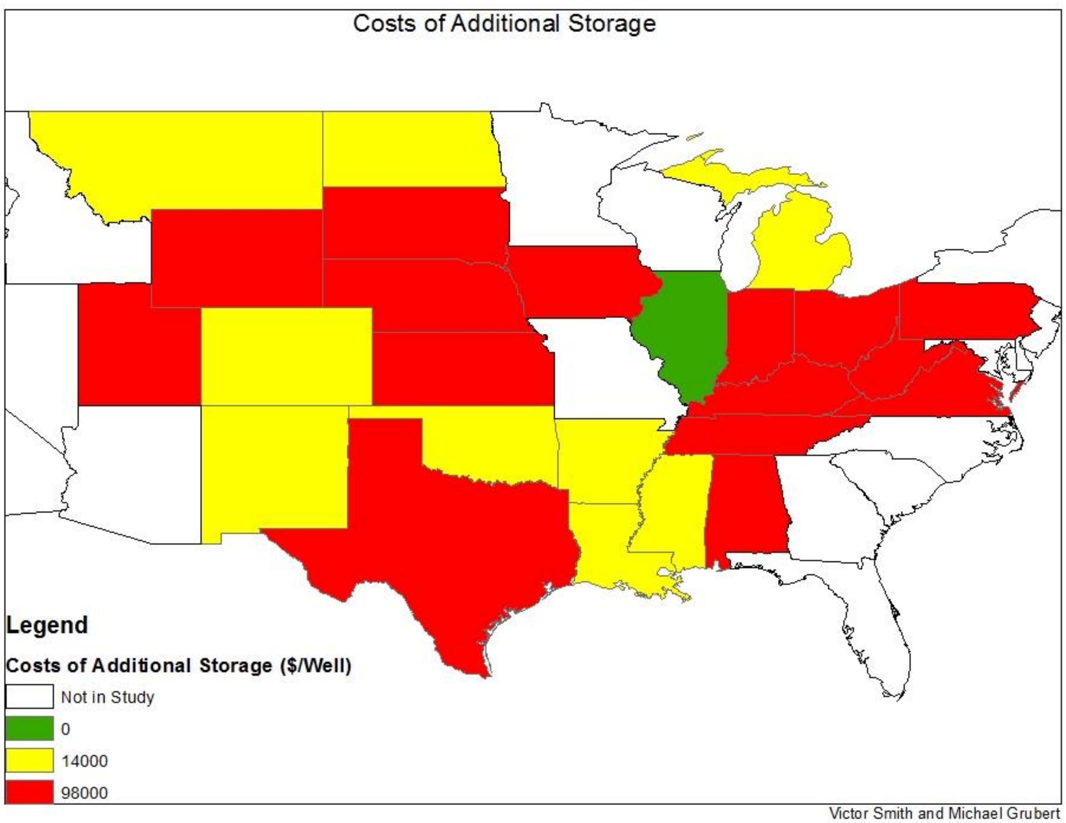


Figure 10: costs of additional storage ($/well)

[85] Hetley, Seydor, et al., 2011, 47

were assumed to have used only pits to store flowback, and therefore it was assumed that each site would require an additional fourteen steel tanks to meet storage requirements. The total increased cost for these states is $98,000.[86] Those that had requirements of some sort were assumed to have half of the storage capacity necessary, and therefore would only need an additional seven steel tanks. The total for increase for these states is an additional $14,000.[87] These costs are shown in figure 10 above.

Cost Aggregation

Although the costs gathered thus far have been compiled on a state-by-state level, the NEMS model does not run on a state level. Instead, NEMS has divided the country into nine different geographic divisions.[88] These divisions, and the number of natural gas wells in each region (in 2012) are shown in figure 11. In order to use the increased cost of drilling numbers obtained for each state it was first necessary to extrapolate these numbers to the divisional level. This was similar to the process done at the end of the process that determined recycling costs by state.

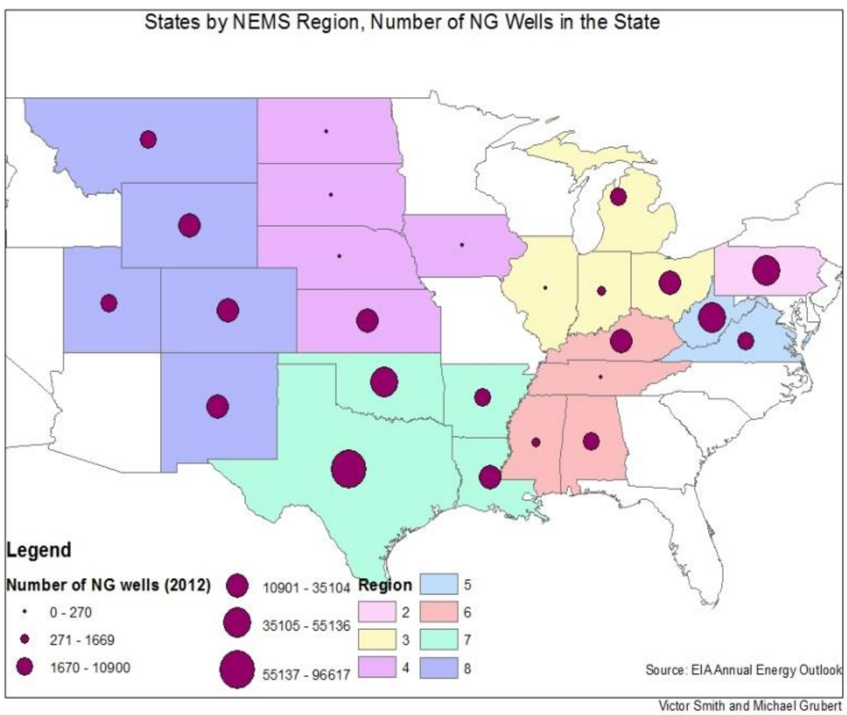


Figure 11: NEMS divisions and number of NG Wells per Region

[86] This is $168,000 less $70,000
[87] Half of $168,000 ($84,000) less $70,000.
[88] EIA, 2009, The National Energy Modeling System: An Overview

Again, it was necessary to use a weighted average. Each state had its total costs summed and multiplied by the total number of natural gas wells in each state, and then divided by the total number of gas wells in the division. This was done so that each state's cost would have an impact on the division's total cost proportional to the amount of drilling expected to be done in each state. Final additional costs per well by region are shown below in Figure 12.

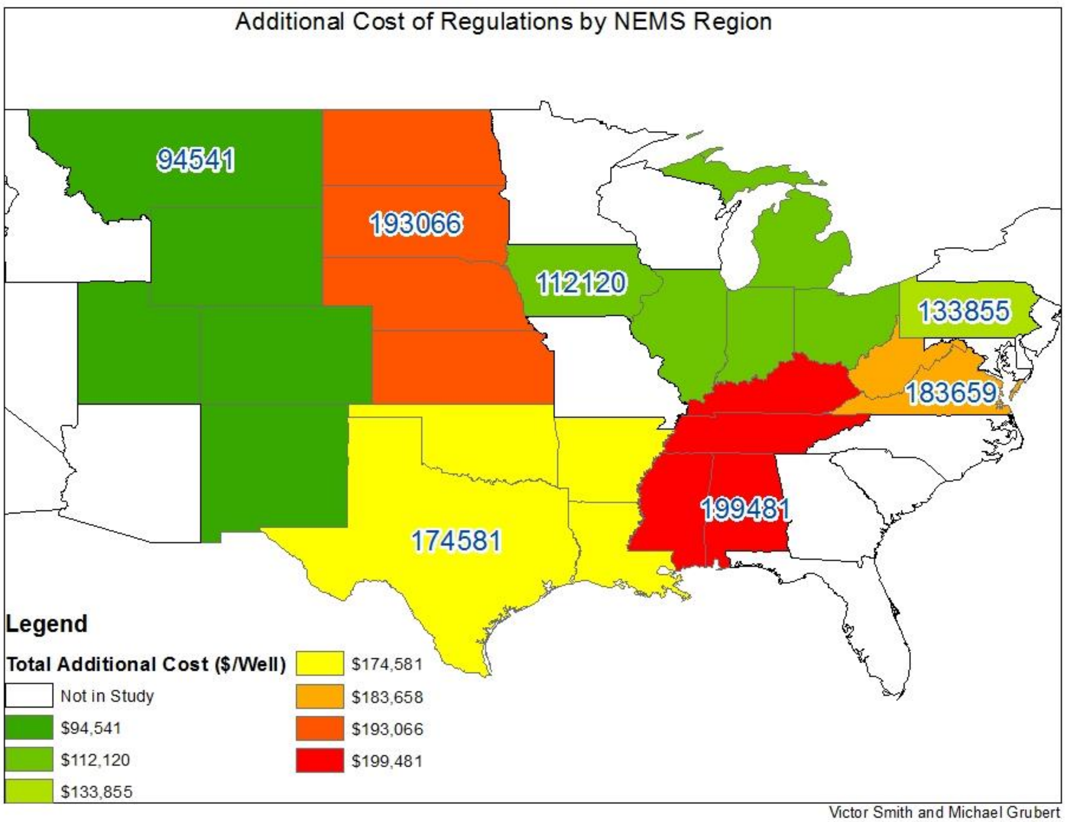


Figure 12: Total additional costs of regulation by region ($/well)

Future Impacts

While these costs per well are going to have an immediate impact on drilling for natural gas, they are also going to have an impact on the future of the natural gas industry, such as supply and natural gas cost. To estimate these future impacts, we used the National Energy Modeling System to create a scenario analysis of these strong policies.

The National Energy Modeling System (NEMS) is a computer based modeling program that helps predict the future of the U.S. energy and economic sectors. By using hundreds of assumptions and historical data, NEMS tries to accurately predict what the energy sector will look like in the future, normally up to 25 years. It helps predict things such as production, consumption, imports/exports, and prices of energy by simulating their market characteristics. It was created by the EIA, and is the basis for their yearly energy outlooks.[89]

All of the data and assumptions that NEMS relies on are located in files called input files. For our scenario analysis, we were concerned about the input file that contained information on the lower 48 states oil and gas wells. Here contains information such as well depths, production factors, and most importantly for our study, the cost of the well. These costs are only broken down into natural gas, oil, and dry wells, so we could not specifically add costs to shale gas development. It is not broken down by state however, but by region. NEMS uses 9 regions across the country.[90] To convert our data to these regions, we weighted the cost per state in each region by the number of current natural gas wells. There are also a number of different costs that determine the cost per well, such as capital costs and variable costs. While it would be best to have our costs change depending on the production of the well and many other factors, we only determined a generalized cost. As a result, we chose to add our costs to the capital cost, as it is a fixed number. Once NEMS is run, these costs will be used in the economic evaluation of the project. The project is economical if the Net Present Value is greater than 0. If it is less than 0, then the project is uneconomical and will not be constructed. This difference in production of natural gas is of course going to have rippling affects beyond the costs of drilling a well. This is going to impact the supply of gas, which will impact the price, and so on. Since NEMS looks into the entire energy sector, changes will be seen in many other areas.

Once the model has run, the future impacts of these costs can be determined. NEMS produces results on virtually everything in the energy sector, from residential natural gas consumption to the retirement of coal plants. Of course not all of this data is useful for relating it back to the increased well costs. To see the actual changes in the energy sector, we compared our results to the AEO reference case from 2012. These results are based on the assumption that things continue to occur as business as usual. Our model ran off these assumptions as well, just with higher capital costs for natural gas wells.

Results

After running the model, there were some very interesting results. The appendix shows a variety of different graphs that show what the impact of additional costs on natural gas wells would be. As expected, the price of natural gas was more expensive. On average the wellhead price of natural gas was $.37 per thousand cubic feet of gas more expensive between the years 2014-2035, with a maximum difference of $.64 per thousand cubic feet of gas. This represents what the impact would be because of these addition costs on the wells. With a natural gas well

[89] EIA, 2009, The National Energy Modeling System: An Overview
[90] EIA, 2009, The National Energy Modeling System: An Overview

being more expensive, the gas that is produced is going to come at a higher price. Eventually price difference becomes large enough that fewer wells will actually be drilled. This trend starts in about 2021, with an average difference of just over 1,000 less wells drilled per year. With less wells drilled, there will be less natural gas supply in the United States, which starts to become much less than the baseline scenario around the same year of 2021.

Besides the direct impact on the natural gas industry, there will also be widespread energy sector impacts due to the higher natural gas prices, and less supply. While the baseline scenario had plans for significant increases in natural gas combined cycle plants, this is no longer the case, and a total of 77 Gigawatts worth of plants will no longer be built. The increase in natural gas prices renders these plants uneconomical. Instead, coal plants will be built to make up for the electricity generation. The rise in coal power plants and decline in natural gas plants coincides with the decrease in natural gas wells being drilled. There is a significant decline in wells being drilled around 2026, when the transition between fuels begins to switch from natural gas to coal.

With no present carbon regulations in the baseline, as they have not become law, coal remains a very cheap fuel. Because of this, the price of electricity is actually cheaper in our scenario, with an average price of $0.47 per kWh lower than the baseline. The natural gas price is expected to rise at a higher rate than the price of coal, making fuel prices overall less expensive. This is why electricity prices are then cheaper. While this price is not very significant, it is still lower. Coal is also a much more carbon intensive resource, and carbon emissions will be higher in our scenario, with an average of .18 mm tons CO_2/per capita being released between the years of 2014-2035.

In conclusion, with additional costs being put on natural gas wells, the price of gas will be higher. Coal will become more competitive as a resource for electric generation plants and more coal plants will be built instead of the planned natural gas plants predicted in the baseline scenario. This cheap source of energy will bring electricity prices down slightly, but also increase carbon emissions. These results are unlikely realistic however, as the EPA is currently working on carbon pollution regulations for new and existing power plants.[91] An updated model that takes these into account would provide for more realistic results. Our results assume a business as usual regulatory climate, and show what would happen if additional costs were put on natural gas wells under these assumptions.

Conclusion

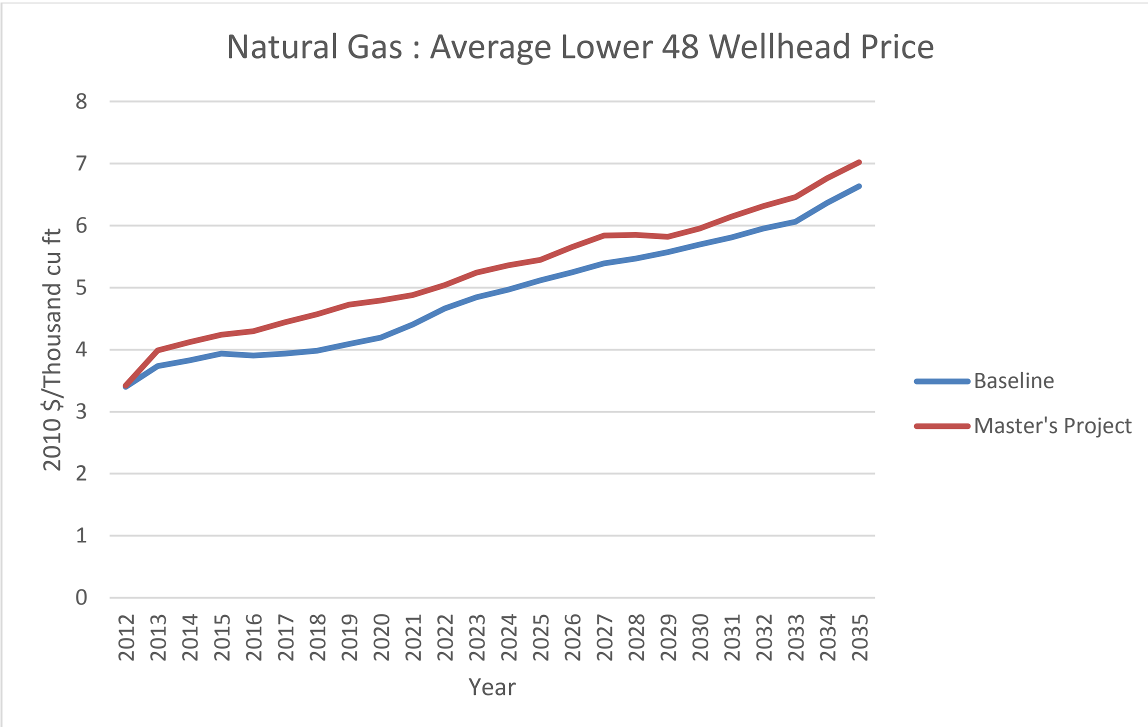
As the potential threat of water contamination during natural gas extraction continues to be a hot topic across the United States, it is likely that stricter regulations will be put in place. Currently regulations vary immensely depending on which state is examined. While not a new technique, hydraulic fracturing and horizontal drilling for natural gas has been ignored by the federal government by using a variety of loopholes, and regulations have been left for each individual state to decide. States have been catching up and creating these regulations, and

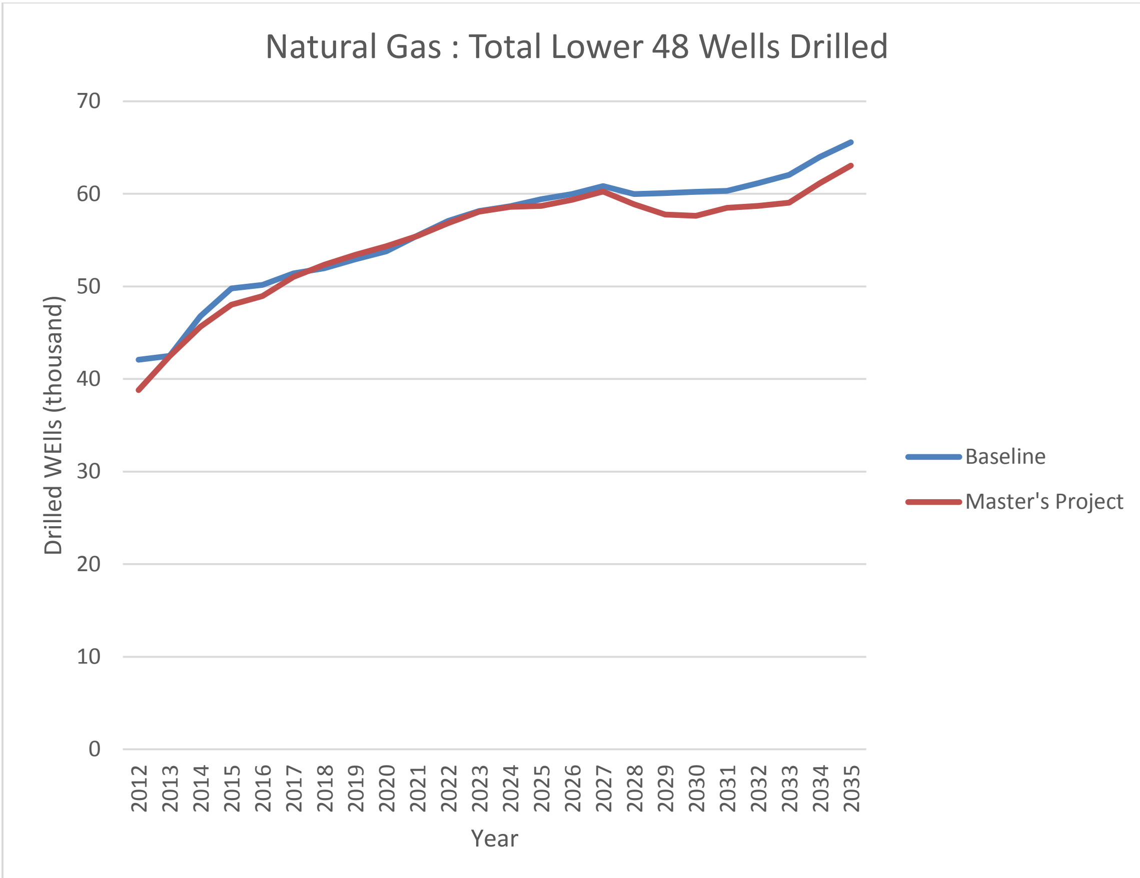
[91] EPA, 2014, 2013 Proposed Carbon Pollution Standard for New Power Plants

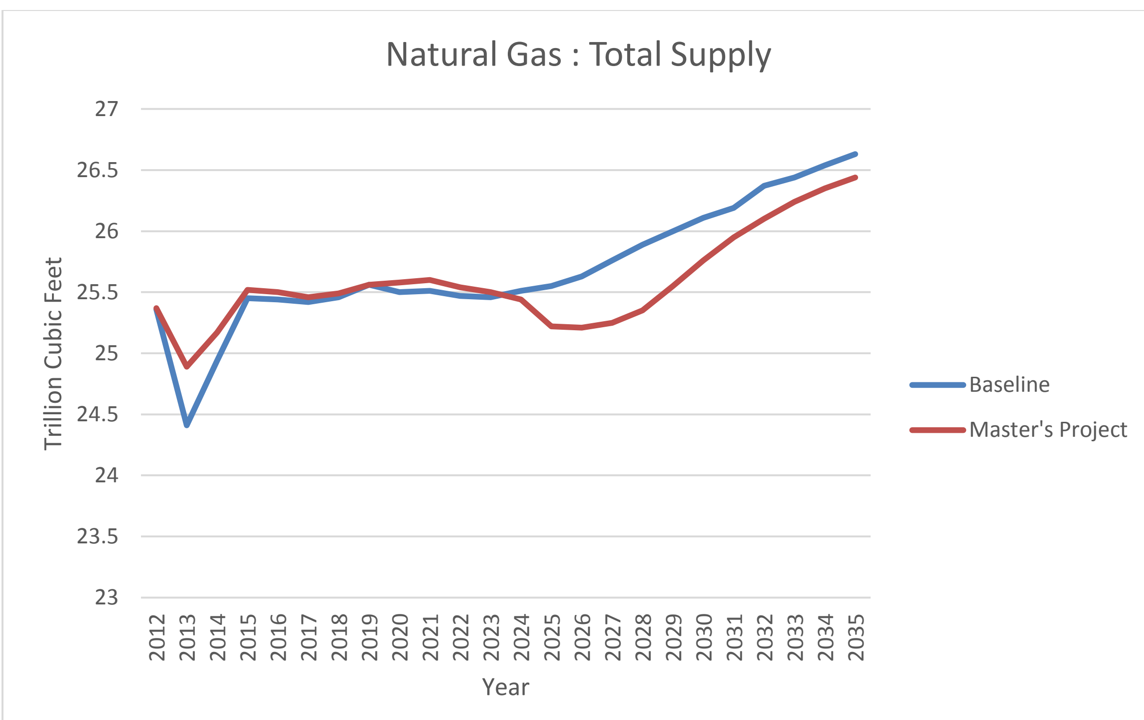
continue to do so. Stricter regulations will likely have an impact on natural gas prices, which could lead to more coal use if carbon regulations are not put in place. In order to best protect our water resources, stricter regulations will be necessary in the future.

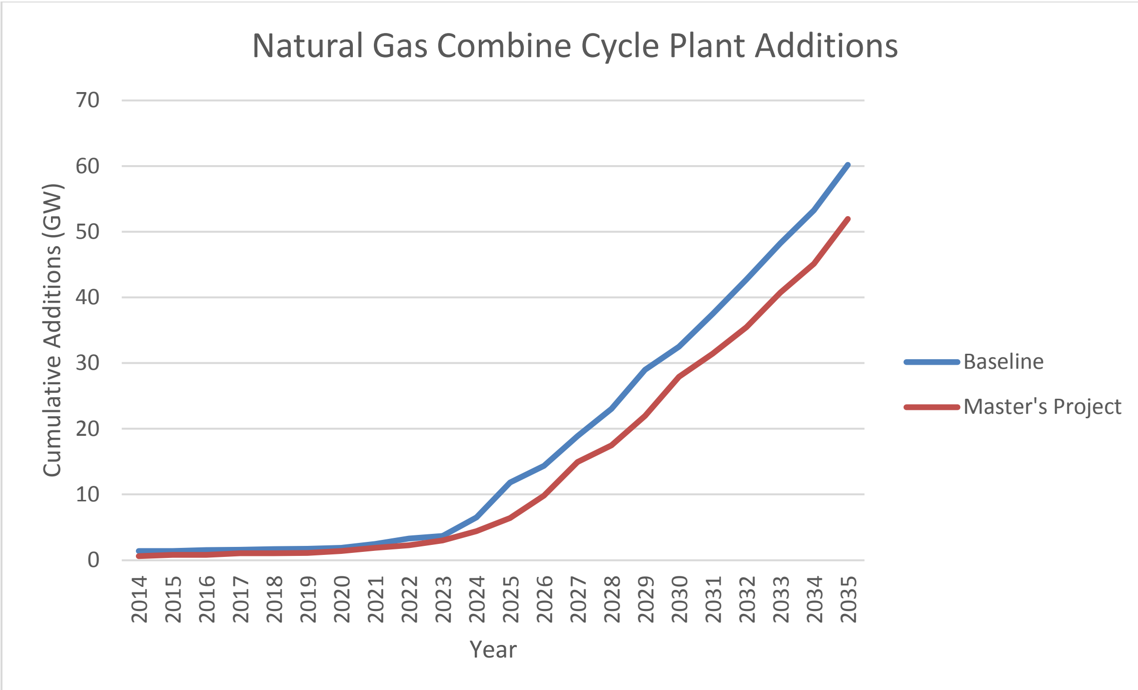
Appendix.

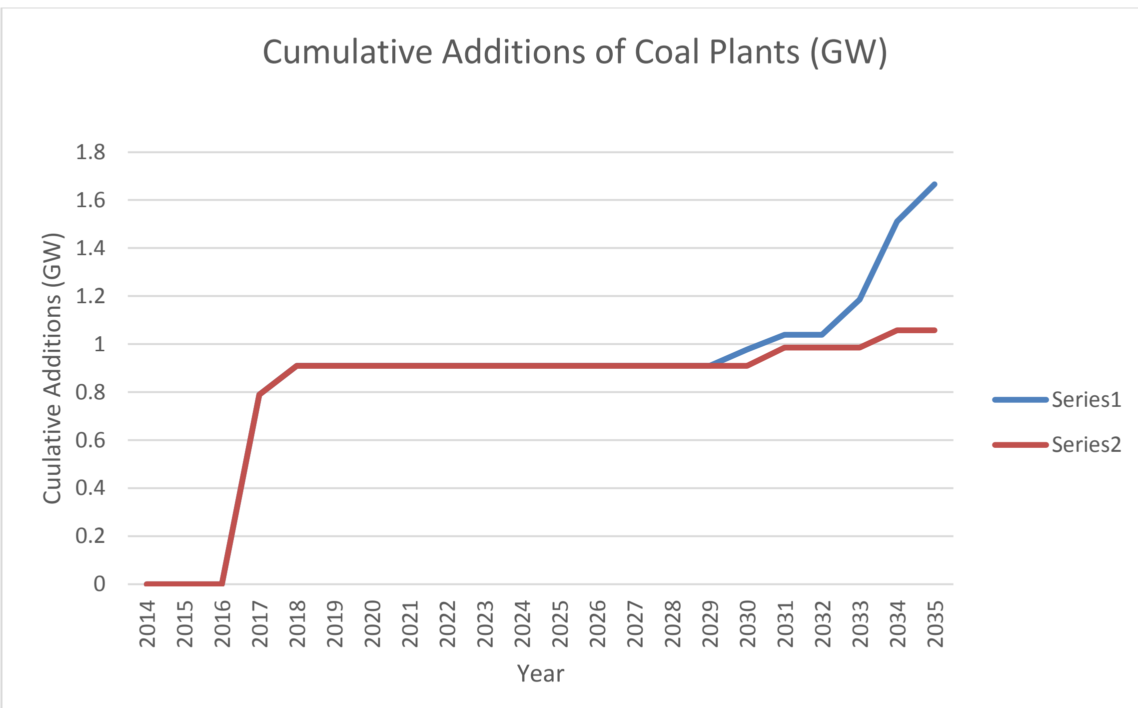
Graphs from NEMS results

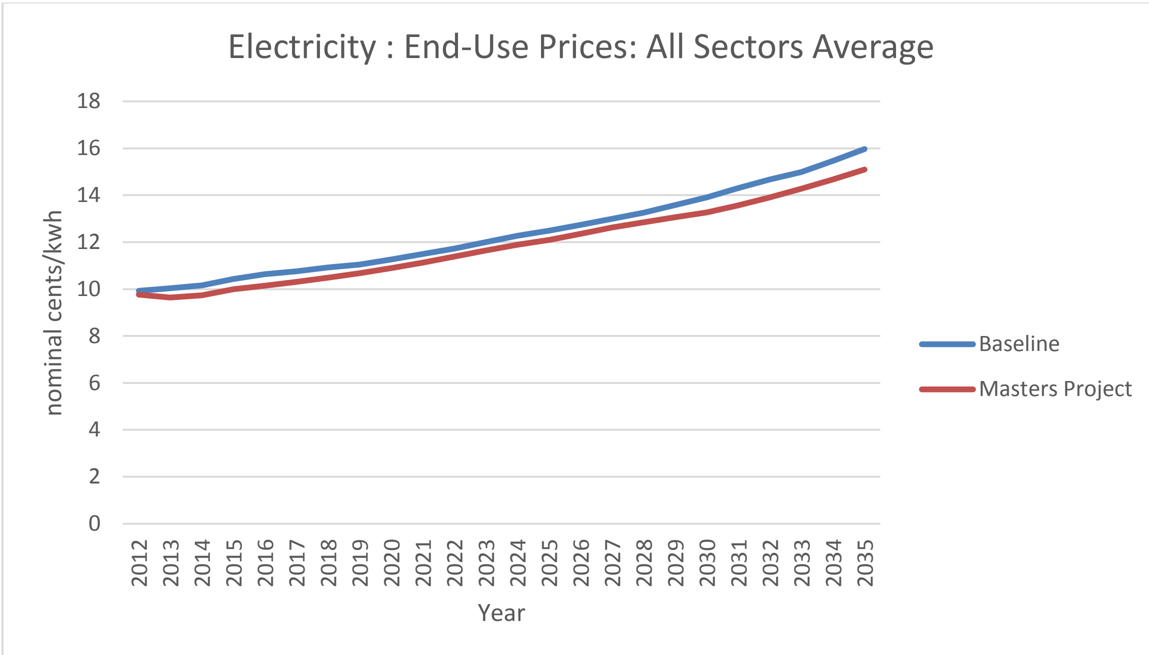


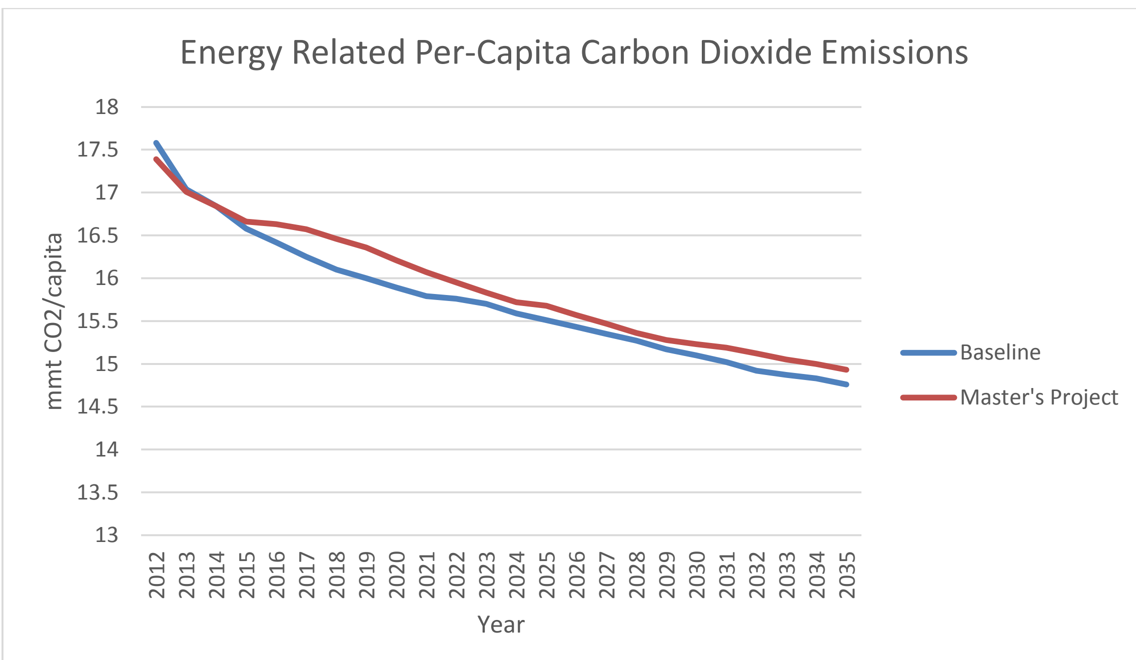

Natural Gas : Total Lower 48 Wells Drilled
Drilled WElls (thousand)
Year
Baseline
Master's Project


Natural Gas : Total Supply
Trillion Cubic Feet
Year
Baseline
Master's Project


Natural Gas Combine Cycle Plant Additions
Cumulative Additions (GW)
70
60
50
40
30
20
10
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year
Baseline
Master's Project


Cumulative Additions of Coal Plants (GW)
Cuulative Additions (GW)
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year
Series1
Series2


Electricity : End-Use Prices: All Sectors Average
nominal cents/kwh
18
16
14
12
10
8
6
4
2
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year
Baseline
Masters Project


Energy Related Per-Capita Carbon Dioxide Emissions
mmt CO2/capita
18
17.5
17
16.5
16
15.5
15
14.5
14
13.5
13
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Year
Baseline
Master's Project

Total cost of regulations for each state

State	Region	Casing	Baseline Testing	Recycling Costs	Costs of Additional Storage	Total
Alabama	6	$46,992.59	$8,000.00	$76,190.48	$98,000.00	$229,183.07
Arkansas	7	$10,963.70	$8,000.00	$66,964.29	$14,000.00	$99,927.99
Colorado	8	$38,477.78	$4,000.00	$0.00	$14,000.00	$56,477.78
Illinois	3	$13,857.41	$0.00	$0.00	$0.00	$13,857.41
Indiana	3	$10,185.19	$8,000.00	$0.00	$98,000.00	$116,185.19
Iowa	4	$7,403.70	$8,000.00	$0.00	$98,000.00	$15,403.70
Kansas	4	$21,077.78	$8,000.00	$0.00	$98,000.00	$127,077.78
Kentucky	6	$11,759.26	$8,000.00	$0.00	$98,000.00	$117,759.26
Louisiana	7	$71,674.07	$8,000.00	-$32,380.95	$14,000.00	$61,293.12
Michigan	3	$7,379.26	$8,000.00	$40,476.19	$14,000.00	$69,855.45
Mississippi	6	$56,248.15	$8,000.00	$72,500.00	$14,000.00	$150,748.15
Montana	8	$44,735.19	$8,000.00	$0.00	$14,000.00	$66,735.19
Nebraska	4	$55,533.33	$7,000.00	$0.00	$98,000.00	$160,533.33
New Mexico	8	$40,878.70	$8,000.00	$64,642.86	$14,000.00	$127,521.56
North Dakota	4	$60,814.81	$8,000.00	$65,873.02	$14,000.00	$148,687.83
Ohio	3	$39,217.04	$6,000.00	-$17,857.14	$98,000.00	$125,359.89
Oklahoma	7	$43,105.56	$8,000.00	$64,642.86	$14,000.00	$129,748.41
Pennsylvania	2	$25,851.85	$8,000.00	$2,003.57	$98,000.00	$133,855.42
South Dakota	4	$55,014.81	$8,000.00	$0.00	$98,000.00	$161,014.81
Tennessee	6	$48,474.07	$8,000.00	$0.00	$98,000.00	$154,474.07
Texas	7	$61,538.27	$8,000.00	$55,408.16	$98,000.00	$222,946.43
Utah	8	$62,727.78	$8,000.00	$0.00	$98,000.00	$168,727.78
Virginia	5	$49,604.81	$6,000.00	$0.00	$98,000.00	$153,604.81
West Virginia	5	$43,068.89	$6,000.00	$35,714.29	$98,000.00	$182,783.17
Wyoming	8	$73,438.89	$2,000.00	-$83,333.33	$98,000.00	$90,105.56

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